January 23, 2014

New England Power Company d/b/a National Grid
Interstate Reliability Project, EFSB 12-1/DPU 12-46/12-47

I. OVERVIEW OF THE PROJECT

Applicant: New England Power Company d/b/a National Grid ("NEP")

Description of Proposal: The Interstate Reliability Project ("IRP") is a proposed overhead 345 kV transmission line along existing rights-of-way ("ROWs"), extending approximately 15.4 miles from a terminus at the Millbury No. 3 Switching Station in Massachusetts through the towns of Millbury, Sutton, Northbridge, Uxbridge, and Millville to the Rhode Island border where it continues for 4.8 miles to the West Farnum Substation; an additional 54.5-mile 345 kV segment of IRP connects the West Farnum Substation with the Card Street Substation in Lebanon, Connecticut. IRP also consists of additions to existing 345 kV and 115 kV facilities and improvements to the Millbury No. 3 Switching Station and other stations in Rhode Island and Connecticut. The estimated cost of the Massachusetts portion of IRP ("Project") is $100.1 million (2011$) (Exh. NEP-1, at 5-73); the estimated cost of the entire IRP is $542 million (Exh. NEP-1, app. 1-5, at 11). Figure 1 below shows the location of the Massachusetts and Rhode Island portions of IRP. Siting agencies in Connecticut and Rhode Island have already approved their jurisdictional segments of IRP.

Proposed as a reliability project, IRP is designed to: (1) increase the transmission transfer capability from western New England to eastern New England and vice versa; (2) increase the transmission transfer capability into and out of Connecticut and Rhode Island; and (3) reliably deliver power among these areas as needed in the event of contingencies. ISO-New England ("ISO-NE") first asserted a need for IRP in a 2008 study and reconfirmed its conclusion in subsequent ISO-NE studies in 2011 and 2012.

Noticed Alternative Route: The Company's Petition also includes a Noticed Alternative Route, which is 29.2 miles long in Massachusetts, and would be located in the towns of Millbury, Sutton, Grafton, Upton, Milford, Medway, Bellingham, Franklin, and Wrentham continuing to the West Farnum Substation in Rhode Island. The estimated cost of the Massachusetts portion of the Noticed Alternative Route is $247.1 million (Exh. NEP-1, at 5-72).

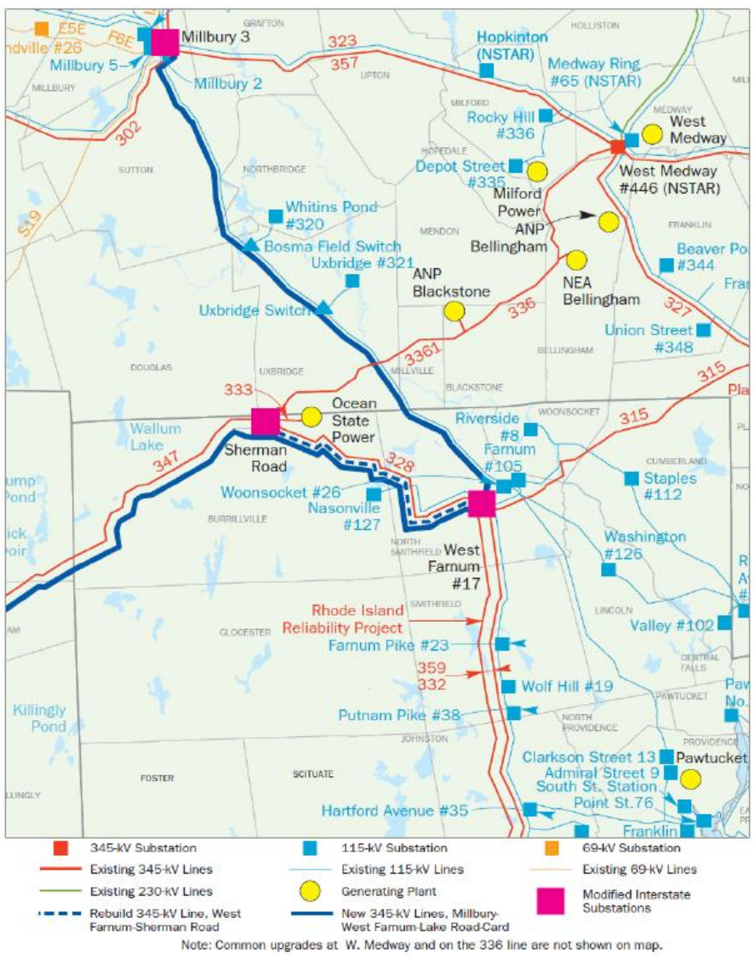
Intervention: The Attorney General, ISO-NE, Matthew Buskell, and Pembroke Realty Trust are intervenors in the case. The Attorney General and ISO-NE both take the position that the Project is needed. The other intervenors were not active in the case and did not submit briefs.

Procedural History: The Petition was filed on June 21, 2012, and the Energy Facilities Siting Board ("Siting Board" or "Board") conducted public comment hearings in Uxbridge on August 14, 2012 and in Milford on August 16, 2012. The Siting Board issued four sets of information requests to NEP and two sets to ISO-NE. Board staff held eight days of evidentiary hearings in February, March, and August 2013. Initial briefs were filed on November 1, 2013 and reply briefs were filed on November 8, 2013.

Approvals Sought: The Petition seeks approval to construct and operate the Project pursuant to G.L. c. 164, § 69J, § 72, and individual and comprehensive zoning exemptions in Millbury, Sutton, Northbridge, Uxbridge, and Millville pursuant to G.L. c. 40A, § 3.

Environmental Impacts: The Project's 345 kV transmission line would be constructed in an existing ROW in Massachusetts presently occupied for most of its length by two 115 kV transmission lines and by the remaining structures of a double-circuit 69 kV transmission line that was taken out of service in the 1990s. The Company proposes to locate most of the proposed 345 kV transmission line in the area now occupied by the retired 69 kV structures. The new line would travel through a mix of undeveloped forested land and suburban areas characterized by low- to medium-density residential development. Staff asked a variety of environmental impact questions concerning topics such as land use, wetlands, visual impacts, electric and magnetic fields, habitat, traffic management, and construction noise. Staff's review of the Company's Petition, its responses to information requests, and follow-up questions during evidentiary hearings, has not identified any significant environmental issues.

Figure 1: Proposed Location of IRP (Exh. NEP-1, at 3-5)



II. SUMMARY OF ISSUES PRESENTED FOR BOARD CONSIDERATION

The following issues are presented for the Board's consideration:

1. **Determination of Need** Has the Company demonstrated that the Project is needed? [See pp. 3 to 6].

2. **Project Approach** Has the Company demonstrated that the Project is superior to alternative Project approaches (including non-transmission alternatives or "NTAs")? [See pp. 6 to 12].

3. **Route Selection** Should the Siting Board continue to require a Noticed Alternative Route in all cases involving a § 69J jurisdictional transmission line? [See pp. 12 to 15].

4. **Zoning** Should the Board grant the individual and comprehensive zoning exemptions requested for the Project? [See pp. 16 to 17].

III. NEED

A. Demonstration of Need

G.L. c. 164, § 69J requires applicants to demonstrate a need for additional energy resources. In its Petition, NEP showed the results of modeling electricity flows into: (1) eastern New England (from western New England and Rhode Island); (2) western New England (from eastern New England and Rhode Island); and (3) Rhode Island.[1] See Figure 2 below. Each of these regions was modeled and tested individually with significant internal generation outages ("initial stress") to determine whether these sub-regions as well as the overall New England system would be able to serve customer loads with the modeled initial stress and two additional unplanned outages of transmission or generation elements (known as an "N-1-1 contingency"). The Greater Rhode Island area was treated as part of western New England when evaluating eastern New England reliability, and was treated as part of eastern New England when evaluating western New England reliability. Connecticut was also studied as a region by itself.

Assuming a substantial amount of generation out of service in eastern New England, the most severe transmission constraint within the region appears to be the ability of the electric grid to serve eastern New England during peak summer periods. Accordingly, this Issues Memorandum focuses primarily on the ability of the overall electric system in New England to serve customers in eastern New England.

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1 NEP performed the electricity flow modeling as a member of a study group that included representatives from Connecticut Light & Power and NSTAR, and was led by ISO-NE. Such study groups are formed by ISO-NE as part of its Regional System Planning Process as described in Attachment K of ISO-NE's Open Access Transmission Tariff.

Figure 2: New England East-West Interface (Exh. NEP-1, at 2-7).

ISO-NE's base case for eastern New England assumed Hydro-Quebec Phase II and interconnections with New Brunswick as being out of service, and Seabrook Nuclear Station as unavailable.[2] In addition, 80 percent of quick-start capability in eastern New England (643 MW) was also assumed out of service, as well as another 365 MW of hydro units. Together, these units represented 4,953 MWs that were modeled as not available to serve customer loads (Exh. NEP-1, app. 2-5, at 26 (Table 3-10)). ISO-NE also considered a sensitivity case in which it reduced its assumed outages from 4,953 MW to 4,253 MW by adding back 700 MW associated with New Brunswick exports to New England.

With the base case and sensitivity case selected by ISO-NE, the model showed that the transmission system would be inadequate to carry the necessary electric flows after N-1-1 transmission contingencies for both near-term electric loads and ten-year forecasted electric loads (Exh. NEP-1, app. 2-5, at 42-43). ISO-NE provided these modeling results for only one base case and one sensitivity case, both of which appear to be more conservative (i.e., stressful) than a typical "two-generator-out" base case scenario. In particular, staff noted that both the base case and sensitivity cases presented by ISO-NE included not only two large generators out,[3] but also a third large generator out of service and/or a number of other smaller generators out of service (Exh. NEP-

2 Typically, transmission lines are not assumed to be out of service as part of the base case initial stress conditions. Hydro-Quebec Phase II has a forced outage rate that is significantly lower than large electric generation in New England (Exh. EFSB-ISO-17(1)). Nevertheless, ISO-NE assumed Hydro-Quebec Phase II to be out of service in the base case because it is one of the two largest resources in the area (Exh. NEP-1, app. 2-5, at 26).

3 Staff requested ISO-NE to provide a list of additional base cases that may also have been run by ISO-NE to determine a need for IRP (Exh. EFSB-ISO-138). ISO-NE responded that they did not consider any additional base cases that were not already described in the September 2012 Needs Assessment.

1, app. 2-5, at 26). Therefore, staff requested ISO-NE to conduct additional modeling runs using a range of different base case assumptions, all expected to be less conservative than the ISO-NE assumptions discussed above.

Staff requested NEP to model four additional base cases in which Hydro Quebec Phase II is in service (and assumed to transfer 1,400 MW) with either Mystic Unit 9 or Pilgrim Nuclear Station out of service (in addition to Seabrook Nuclear Station being out of service) (RR-EFSB-64). In two of the cases, New Brunswick can transfer 735 MW into eastern New England, and in two of the cases New Brunswick can transfer 124 MW to eastern New England.[4] The additional base cases also included Footprint Power and Cape Wind, which were not previously included by ISO-NE because they had not yet participated in the Forward Capacity Market ("FCM"). The results generally showed a reduced need for additional energy resources, and it was not clear that a project as large as IRP would be necessary.

However, recent requests to ISO-NE by existing generators for permission to retire approximately 2,480 MWs of electric generation have profoundly altered the outlook on the need for IRP shown in the sensitivity cases requested by staff. NEP submitted a supplemental response in which the Company stated that it had been notified by ISO-NE of the following Non-Price Retirement ("NPR") requests commencing with the 2017-2018 capacity commitment period: (1) Brayton Point Units 1-4; (2) Brayton Diesel Units 1-4; (3) Bar Harbor Diesels; (4) Medway Diesels; (5) Bridgeport Harbor 2; (6) John Street Units 3, 4, and 5; (7) Ameresco SEMA Demand Response ("DR"); and (8) EnerNOC DR (RR-EFSB-64, 2S). The sum of these retirement requests equals approximately 2,480 MW, of which 1,535 MW are at Brayton Point in Somerset. The great majority of the retirement requests in MWs were from resources located in eastern New England. These retirements are in addition to Vermont Yankee's recent retirement announcement, which represents an additional 604 MW. NEP's power flow analysis demonstrates that if the retirement requests are granted – even assuming the less stressful base case scenarios requested by staff – there would be numerous transmission lines that could become thermally overloaded, including eight 345 kV transmission lines and 13 115 kV transmission lines (under various N-1-1 contingencies) (RR-EFSB-64, 2S at 9-10).

NEP submitted another supplemental response in which it reported that ISO-NE had performed a reliability analysis for Brayton Point's Non-Price Retirement ("NPR") that demonstrated a need for Brayton Point Units 1-4 (RR-EFSB-64, 3S). As a result, ISO-NE rejected Brayton Point's request to retire Units 1-4. The Company also presented the results of ISO-NE's sensitivity analysis, which modeled the full IRP in service in order to understand the impact on reliability. This sensitivity analysis shows that with the full IRP in service, there is a reliability need

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4 The Hydro-Quebec Phase II transfer assumption of 1,400 MW was based on ISO-NE "Morning Report" average flows on the top ten peak days (Exh. EFSB-20). The New Brunswick transfer assumptions reflected the range of scheduled imports on the top ten peak days (Exhs. EFSB-20; EFSB-RR-42).

for Brayton Point Unit 1 (239 MW), but not for Brayton Point Units 2, 3, and 4 (RR-EFSB-64, 3S at 2).[5] The ISO-NE evaluation reinforces the reliability need for IRP.

B. Future Filing Considerations

As reflected by the discussion above, the modeling results can vary greatly depending upon which base case assumptions have been adopted to create the initial stress on the modeled transmission system, i.e., the condition of the system that is assumed to exist before studying the effect on the transmission system of certain N-1 and N-1-1 contingencies. In this proceeding, the Company submitted only one base case and one sensitivity case for the west-to-east evaluation. During the course of the proceeding, staff asked the Company and ISO-NE to conduct a number of additional model runs based on alternative base cases for the purpose of determining exactly how sensitive the model results were to changes in base case assumptions. These additional modeling runs were useful for this purpose, and the Siting Board might consider requiring petitioners in the future to submit multiple model runs, consistent with the facts and circumstances of each case, to demonstrate the sensitivity of the results to material changes in base case assumptions.

Questions for the Board

1. Has the Company demonstrated that the Project is needed?

2. In the future, should a petitioner be required to submit a range of base case model runs to demonstrate how sensitive the model results are to changes in the base case assumptions?

IV. PROJECT APPROACH

A. Overview of Project Approach Alternatives

The Company submitted an extensive analysis, prepared by ICF Resources, LLC (“ICF”), regarding the feasibility of using an array of Project approach alternatives to meet the identified need. The ICF studies focused on demand-side non-transmission alternatives (“NTAs”), such as energy efficiency (“EE”) and active demand response (“DR”), and supply-side NTAs such as new central generation and distributed generation (“DG”) – supplemented by scaled-back transmission improvements as part of a “Hybrid” variation. Specifically, the Company considered the ability of the following potential Project approaches to address the identified need:

- A combination of NTAs (new generation, EE, DR, and DG);
- The Connecticut-to-Rhode Island segment of IRP only – with no construction in Massachusetts – plus NTAs;

[5] ISO-NE’s determination that the Brayton Point units are necessary for reliability purposes provides the Brayton owner the option to choose to operate on a market price or cost-of-service basis. However, if the Brayton owner chooses to not operate, ISO-NE does not have the authority to require the Brayton units to operate after May 31, 2017 (See RR-EFSB-64, 2S and 3S).

- A “Hybrid Alternative” consisting of the Connecticut and Rhode Island sections of IRP, plus scaled-back transmission upgrades to the existing 115 kV system in Massachusetts, supplemented by NTAs;
- An underground transmission alternative.[6]

ICF developed a model using scenarios similar to those used by ISO-NE in its base case evaluation of need (Exh. NEP-1, app. 3-2, at 30-32) and evaluated the Project approach alternatives listed above under various load growth, NTA growth, and generation retirement scenarios. ICF studied whether these Project alternatives would eliminate modeled thermal and voltage violations, and if so, how they would compare to the Project based on reliability, cost and environmental criteria.

1. Potential for NTAs Alone to Resolve Identified Need

As shown in Table 1 below, ICF estimated the amount of NTA capacity, including new generating resources, EE, and DG, available in southern New England through 2020 to help resolve the identified capacity need. ICF subtracted these contributions from the need totals in aggregate for southern New England to arrive at the gap between anticipated NTAs and total required resources, as shown below. ICF presented two estimates of future NTA resources: a reference case that represents ICF’s best estimate based on then-current state programs, FCM results and the ISO-NE new generation queue; and an aggressive case that represents “higher, yet reasonably achievable growth” in resources (Exh. NEP-1, app. 3-1, at 5.2). In both cases, there remains a significant resource gap unmet by NTAs – although these figures do not include DR, addressed below.

6 Undergrounding would likely have fewer permanent environmental impacts than the proposed overhead transmission line, if it were constructed beneath public roads, but the Company dismissed undergrounding the lines as being more than three times as expensive as the overhead alternative for the section in Massachusetts ($340.5 million versus $100.1 million) (Exh. NEP-1, at 3-53).

Table 1: ICF Evaluation of Non-Transmission Alternatives to Alleviate Thermal Overloads in Southern New England[a]

	Reference Case (MW)		Aggressive Case (MW)	
	2015	**2020**	**2015**	**2020**
Total Resources Needed to Eliminate Identified Reliability Violations[b]	3,312	6,610	3,312	6,610
Less: New Generating Resources from the ISO-NE Interconnection Queue[c]	896	1,790	896	1,790
Less: Incremental EE and DG[d]	342	1,439	405	1,883
Resource Gap Unmet by NTAs	2,074	3,381	2,011	2,937

From Exh. NEP-1, app. 3-2, at 25, 26 (June 2012), except as noted and with staff calculations as noted below.

a. Resource needs and NTAs aggregated across southern New England. See text.

b. "Critical Load Level Reductions" plus "Supply – Combination NTA" (Exh. NEP-1, app. 3-2, at 26).

c. ICF assumed addition of specific units from among 2,850 MW in the ISO-NE Interconnection Queue as of April 1, 2011; most units in the queue were in western New England and thus less useful for relief of west to east stress (Exh. NEP-1, app. 3-1, at 6-1, 6-2, D-3).

d. Exhs. NEP-1, app. 3-1, at 5-16 and NEP-1, app. 3-2, at 26.

a. Potential for Energy Efficiency to Fill the Gap

ICF evaluated the potential for achieving additional peak reductions from EE above base case levels (based on EE amounts in the FCM) in its reference case and aggressive case EE projections for 2015 and 2020. ICF developed its reference case and aggressive case EE estimates based on an evaluation of utility-sponsored efficiency programs and state commitments for future EE investments in southern New England (Exh. NEP-1, app. 3-1, at ES 4). ICF compared its reference case EE analysis with ISO-NE's 2011 "Final Energy Efficiency Forecast," presented to the Planning Advisory Committee in April 2012 (Exh. NEP-1, app. 3-2, at 4, n.5). ICF noted that its reference case EE estimates for southern New England were generally consistent with those in the ISO-NE study (id., at ES 6-7). ICF asserted that EE alone would be insufficient to resolve the identified violations as an NTA solution. ICF also concluded that EE in combination with other NTAs (as shown in Table 1 above) would be insufficient to meet the identified need.

b. Potential for New Conventional Generation to Fill the Gap

ICF also looked at the potential for generation NTAs to solve the identified need in southern New England. ICF highlighted significant uncertainty at the time about the extent of generator retirements (Exh. NEP-1, app. 3-2, at 57-63). ICF specifically mentioned Canal, Mystic unit 7, and Brayton Point unit 4 (totaling 2,113 MW) as candidates for retirement in eastern Massachusetts (Exh. NEP-1, app. 3-2, at 57-63). These or other retirements from the generation fleet will increase the gap between projected NTA contributions and total resources needed to eliminate reliability planning violations. In addition to existing generation retirements, ICF cautioned that there would likely be attrition of some new resources listed in the ISO-NE Interconnection Queue that would also increase the resource gap for NTAs to meet as a potential Project alternative.

c. Distributed Generation

In its initial December 2011 evaluation of NTAs that was rolled into its June 2012 Update, ICF reviewed programs and regulatory trends in Connecticut, Massachusetts, and Rhode Island promoting distributed generation resources such as photovoltaic and wind power (Exh. NEP-1, app. 3-1, at 5-4, 5-7, 5-12). ICF projected installation of ten to 15 MW, 14 to 45 MW, and ten to eleven MWs of DG yearly in Connecticut, Massachusetts, and Rhode Island, respectively (id. at 5-4 to 5-14). For Massachusetts, ICF's reference case assumption of incremental additions of 14 MW per year was extrapolated from a Massachusetts DOER report that 14 MW of renewable distributed generation was installed in 2009; the more aggressive assumption of 45 MW per year was extrapolated from a projected addition of 45 MW in 2011 (id. at 5-12). Since the sun and wind are intermittent resources, ICF included assumptions that at times of peak load, photovoltaic resources would produce 28 percent of installed capacity and wind would produce ten percent of installed capacity (id.).

In August 2013, ICF supplemented its testimony with respect to solar generation given significant regulatory changes in New England (Exh. PA-42, at 4-6). ICF acknowledged the existing 400 MW goal and proposed 1,200 MW incremental goal for installation of solar generation in Massachusetts (and other significant solar goals in New England) but contends that uncertainties exist regarding the cost and feasibility of modeling solar resource for purposes of transmission reliability planning (id.). ICF noted that peak-hour capacity provided by solar generation is only 30 to 40 percent of its nameplate rating. ICF further stated that modeling the contribution of solar generation to long-term reliability is difficult as there is almost no prior experience in the region as a guide and that ISO-NE has acknowledged the need to analyze and address the technical issues as part of a working group over the next year (Tr. 4, at 682-683; Tr. 5, at 800-801, 819). In advance of such methods to be developed by ISO-NE, ICF asserts that planning and modeling solar resources creates uncertainty as to how solar generation should be integrated into an NTA analysis (Exh. EFSB PA-42, at 4).

d. Potential for Demand Response to Fill the Gap

After consideration of its aggressive case assumptions about EE, generation additions, and DG, ICF concluded that it would be infeasible to fill the gaps of 2,011 MW in 2015 and 2,937 MW in 2020 with DR (Exh. NEP-1 app. 3-2, at 25). Based on procurement costs in the most recent Forward Capacity Auction at the time of the ICF study (FCA #4), in which DR resources were obtained at a cost of $30/kW-year, ICF calculated that to fill the resource gap with DR would cost New England ratepayers $540/MWh (assuming 50 hours per year of load interruptions) (Exh. NEP-1 app. 3-1 at E-6). Using econometric studies based on industry valuations of lost load ("VOLL"), ICF contends that the economic cost to participating customers for interrupted load would be approximately $8,412 per MWh (Exh. NEP-1 app. 3-1, at E-14).[7] ICF estimated that if sufficient

[7] The observed cost of DR in FCA #4 ($540 per MWh) was approximately six percent of the $8,412 figure calculated by ICF using its VOLL methodology (Exh. NEP-1, app. 3-1, at E-6, E-12).

DR resources could be obtained, the costs (using VOLL) for DR to solve the resource gap (after other NTAs) for Massachusetts alone would range from a low of $261 million per year in 2015 (aggressive case) to a high of $1.02 billion per year in 2020 (reference case) (Exh. NEP-1, app. 3-1, at E-13). Because these amounts are annual, ICF estimated that the cost of incremental DR just for Massachusetts would accumulate up to $14.6 billion on a net present value basis over a 30-year time period (id. at E-15). In addition to costs that ICF regarded as infeasible for DR to address the resource need, ICF voiced further reservations about the role of DR in alleviating the need for the Project:

- DR "fatigue" is likely to degrade the response of Real Time DR should ISO-NE need to call on DR too frequently (Exh. NEP-1, app. 3-1, at F-45, and app. 3-2, at 26-27);
- More recent performance of DR in the electric system has been poorer than anticipated, with actual participation of approximately 40 percent of the amount clearing in the FCM; this derating of 60 percent is lower than anticipated by ISO-NE (Exh. NEP-JR-3, at 6);
- FCA #7 showed a 38 percent reduction in real time DR, relative to FCA #6 (Exh. NEP-JR-3, at 7);
- It is difficult to target DR to specific geographic areas, due to non-discriminatory provisions of state programs, and as shown by historical results (Exh. NEP-1, app. 3-2, at 27).

2. Potential for a Hybrid Alternative to Solve Need

The Company took the additional step of evaluating whether the portion of IRP located in Massachusetts (i.e., the 345 kV line from Millbury, MA, to West Farnum, RI, and related upgrades) could be replaced by a combination of NTAs and a scaled back transmission solution involving upgrades of existing 115 kV lines (Exh. NEP-1, app. 3-2, at 1). ICF updated the reference case it had used to evaluate NTAs alone, to reflect changes in generator availability,[8] and to reflect an expectation of a doubling of energy efficiency peak load reductions relative to the Initial NTA Assessment (Exh. NEP-1, app. 3-2, at 31). The Company evaluated a set of upgrades to 23 miles of existing 115 kV lines (plus two transformers) that would provide service under these conditions over the period from Project completion to 2020 (Exh. NEP-1, app. 3-2, at 4). Not including the cost of NTAs, the conceptual level cost estimate for the 115 kV upgrades is $75 million for the reference case (-25%/+50%), which is considerably less than the $121 million cost of the 345 kV line from Millbury to West Farnum (Exh. NEP-1, app. 3-2, at 9). However, ICF also reported the levels of upgrades that would be required in five sensitivity cases (such as retirement of Canal Station, or a higher peak demand growth rate) and cautioned that:

8 This ICF assessment, completed in July 2012, included changes to reflect the announced retirements of Salem Harbor and AES Thames power plants (Exh. NEP-1, App. 3-2, at 4). The only significant new generation proposals in the ISO-NE interconnection queue for eastern New England were Brockton Power and Cape Wind, and ICF elected to model Cape Wind in only some cases and Brockton Power in none (id. at 5).

- Due to the need to design and permit the 115 kV upgrades, the implementation of the Hybrid Alternative would delay the in-service date of the Project, leaving the transmission system vulnerable to potential thermal overloads for an additional 18 months (Exh. NEP-1, app. 3-2, at 15);
- The cost estimates of the Hybrid Alternative were more preliminary (-25%/+50%) than those of the Project (which were -25%/+25%) and therefore could be expected to increase (Exh. NEP-1, app. 3-2, at 16);
- The program of 115 kV upgrades would need to be significantly expanded in each of five sensitivity cases exploring a range of scenarios related to load growth, amounts of EE and DG, and generator retirements; the average cost of the 115 kV transmission upgrades required among six scenarios (reference case plus five sensitivity cases) was $156 million (Exh. NEP-1, app. 3-2, at 15, 47);
- Any delay in in-service date of the Hybrid Alternative might make it necessary to include uplift costs associated with retaining generators requesting to retire (id. at 15-16).

3. Evaluation of a Relaxed Base Case

At the request of staff, ICF performed a spreadsheet analysis of NTA solutions that included: (1) imports from Hydro-Quebec and New Brunswick into eastern New England representing an average flow on selected peak load days; (2) inclusion of Footprint Power and Cape Wind by June 2016; (3) updated CELT load forecasts; and (4) a second generator out in eastern New England (in lieu of assuming Hydro-Quebec Phase II is unavailable) (Exh. EFSB-PA-42(R)). Under this scenario, ICF stated that a spreadsheet analysis resulted in a resource gap of 286 MW by the revised end date of 2022, with smaller gaps in the intervening years (id. at 1). ICF stated that it may be feasible to fill such a gap from 2016 to 2022, but maintained that it would be challenging to do so and that it is doubtful that such an NTA would provide an actual solution to transmission reliability issues (id. at 2).

ICF enumerated many reservations about the analysis requested by staff. ICF noted that in performing only a spreadsheet analysis and not a load flow analysis, it was unable to distinguish the efficacy of a generation resource placed centrally in the load zone from another in a more peripheral location (Exh. EFSB-PA-42(R) at 2). ICF also asserted that some of its earlier evaluations of DR were insufficiently pessimistic, largely based on continuing decreases in active DR bids into the FCM (id. at 2-4). ICF repeated its earlier views on solar as expensive and intermittent (id. at 4-6). ICF also expressed concerns about relying on Hydro-Quebec and New Brunswick imports for reliability purposes absent firm, long-term contracts (id. at 6-7). ICF also expressed concern about power plant retirements following removal of the price floor in FCA #8 (to be held in 2014) and in successive capacity auctions (id. at 7-8). Finally, ICF stated that performance of an NTA would be sensitive to variations in the rate of growth of peak demand (id. at 8).

ICF illustrated the sensitivity of its analysis to assumptions about the generator availability and future NTA levels by exploring sensitivity cases. One sensitivity case assumed retirement of Brayton Point Units 1 through 4, and this increased the 2022 gap from 286 MW to 1,772 MW, with a 1,178 MW gap as early as 2013 (Exh. EFSB-PA-42(A) at 3). A sensitivity case with Hydro-Quebec Phase II modeled as unavailable instead of a second eastern Massachusetts generator increased the 2022 gap from 286 MW to 681 MW (id.). ICF opined that achieving these levels of NTA integration to address the resource gap would likely be costly, difficult, time-intensive, and it questioned whether enough customers would participate (Exh. EFSB-PA-42(R) at 11). ICF further suggested that many unknown issues and risks make the NTA approach far less robust than the Project (id. at 10).

4. Intervenors' Positions

ISO-NE argues that together with the transmission owners, it devoted substantial efforts to identifying a range of potential transmission solutions, from which it selected IRP as the best one (ISO Brief at 27). ISO-NE further argues that the September 2012 Solution Study confirmed that IRP continued to meet the identified need (ISO Brief at 28). The Attorney General reviewed the case record with respect to NTAs and the Hybrid Alternative, and argues that the Hybrid Alternative involves a substantial amount of speculation, risk, and cost uncertainty (AG Brief at 15-16). The Attorney General concludes that IRP is superior to alternative approaches in terms of cost, environmental impact, reliability, and ability to address the identified need (AG Brief at 17).

Question for the Board

> Did the Company adequately evaluate the potential for NTA resources individually and in combination with 115 kV upgrades to meet the need for the Project?

V. ROUTE SELECTION/ALTERNATIVE ROUTE

A. Primary versus Alternative Route

Case precedent, and not statute, establishes the requirement that a petitioner present both a Noticed Primary and Alternative Route. Consistent with Siting Board precedent, the Company submitted a noticed Primary Route as well as a noticed Alternative Route.[9] The Siting Board compares the two route alternatives to determine which is preferable with respect to providing a reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost. In this case, the comparison easily demonstrates that the Primary Route is preferable.

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9 "Noticed" in this context means that both routes were included in the notice of adjudication published and served in the proceeding. Berkshire Gas Company (Phase II), 20 DOMSC 109,153 n.30 (1990). The Siting Board generally requires abutters and certain other groups and municipal organizations to receive notice by regular mail or hand delivery.

Table 2: Key Metrics for Primary and Noticed Alternative Routes

	Primary Route	**Noticed Alternative**
Length of Route - MA/Total (Miles)	15.4/20.2	29.2/37.1
Estimated Cost – MA	$100.1 million	$247.1 million
Estimated Cost – MA + RI	$127.8 million	$293.7 million
Area of Critical Concern (acres)	0	139.4
Tree Clearing (acres)	13.3	95.2
Rare Species Habitat Crossed (acres)	70.7	227.6

As shown in Table 2 above, the Massachusetts portion of the Project's Alternative Route is approximately twice the length of the Project's Primary Route and is estimated to cost almost two and a half times more to construct than the Primary Route (Exh. NEP-1 at 5-72). Further, the Noticed Alternative Route crosses an Area of Critical Environmental Concern ("ACEC") in Upton, uses higher poles, and requires significantly more tree clearing than the Primary Route. Given the factual circumstances presented in this case, the Board may want to consider modifying its long-standing precedent that a Section 69J petitioner must provide notice to abutters and other interested persons along a designated Alternative Route.

B. Siting Board Standard of Review on Requiring a Noticed Alternative Route

G.L. c. 164, sec. 69J provides that a petition to construct a proposed facility must include "a description of alternatives to [the applicant's] planned action" including "other site locations." In order to carry out this statutory directive when reviewing a proposed transmission line facility, the Siting Board developed a standard of review that requires applicants to demonstrate that they have examined a reasonable range of practical alternative routes. The standard of review laid out a two-pronged test that the applicant must meet. New England Power Company, EFSB 10-1/D.P.U. 10-107/108, at 35 (May 16, 2012) ("NEP Hampden"). The first prong relates to developing reasonable criteria and evaluating alternative routes so that the applicant can demonstrate that it did not overlook or eliminate any routes that are on balance clearly superior to the proposed route. Id. This first prong is commonly referred to as the site selection process. New England Power Company, 21 DOMSC 325, 378 (1991) ("NEP Andover"). The second prong requires that the applicant establish that it identified a primary route and at least one additional noticed route with some measure of geographic diversity from the primary route. NEP Hampden at 38; MASSPOWER, 20 DOMSC 301, 371-372 (1990). Thus, case precedent, and not statute, establishes the requirement that at least one "alternative" route be noticed. Therefore, the Board may clarify or modify that precedent in this or a future proceeding.[10]

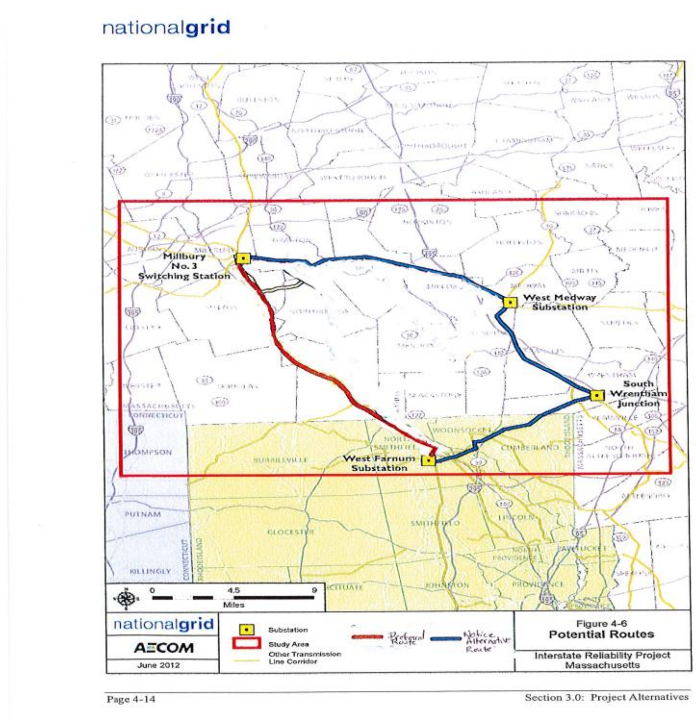
10 Indeed, the Siting Board found that, under the circumstances, a cogeneration facility could establish that a second practical, geographically diverse facility site does not exist (because of the need to be located near the steam host) and need not provide a noticed alternative site. Altresco-Pittsfield Inc, 17 DOMSC 351, 393-394 (1988). In the case of generating facilities, which under deregulation are not required to demonstrate that they are needed, the Siting

The requirement to notice at least one alternative route developed so that the Siting Board could choose the alternative without further proceedings, because the Siting Board "may not approve any site, route, or portion of a route which was not included in a notice of adjudication published in the proceeding." NEP Andover, 21DOMSC at 377. See also Berkshire Gas Company (Phase II), 20 DOMSC 109,153 (1990); MASSPOWER, 20 DOMSC at 372. However, staff research suggests that the Siting Board has not approved an alternative route in at least 25 years.

C. Selection of Noticed Alternative Route for IRP

The selection process led to the identification of the Project route as the Primary Route. To satisfy the second prong, the Company needed to identify an alternative route that offered "some measure of geographic diversity."[11] A quick glance at the map in Figure 3 suffices to demonstrate that the Primary Route would be considerably shorter than any plausible alternative, as it follows a straight line between Millbury Substation and West Farnum Substation. Based on the greater distances involved, among other factors, none of the Alternative Route candidates compared favorably to the Primary Route as to costs and environmental impacts.

Figure 3: Primary Route and Noticed Alternative Route



Board formally abandoned its requirement for a noticed alternative site in 1997 (IDC Advisory Ruling, September 16, 1997).

11 The Siting Board has determined what "some measure" entails on a case-by-case basis.

A. Benefits and Downsides of Requiring a Noticed Alternative Route

The benefits of requiring a Noticed Alternative Route include:

- Requires an in-depth comparison to the Primary Route;
- Provides for the ability of the Company to proceed expeditiously with the Noticed Alternative Route if the Primary Route is denied and the Siting Board approves the Alternative Route (see contrary Company comment below).

The disadvantages of requiring a Noticed Alternative Route include:

- The added cost to survey and notice an Alternative Route (estimated by the Company to be $750,000 in the current case (RR-EFSB-33);
- The potentially unnecessary concerns experienced by abutters to the Noticed Alternative Route even though alternative routes are very rarely selected.

In its response to staff questions about the efficacy of requiring a Noticed Alternative Route, the Company made the following points:

- The requirement for a Noticed Alternative Route increases the complexity of an already technical administrative proceeding (RR-EFSB-33);
- The Noticed Alternative Route requirement is generally not an effective means of mitigating the risk that the Applicant has chosen the "wrong" route (RR-EFSB-33). Applicants typically proceed to permit only the Primary Route with other agencies while seeking Siting Board approval. If the Board were to approve the Noticed Alternative Route, the Company would lose the scheduling advantage of concurrent permitting for the Primary Route (id.);
- In the case of transmission line permitting, if the Siting Board were to approve a more costly Noticed Alternative Route over a Primary Route, ISO-NE may allocate the incremental costs to local (Massachusetts) and not region-wide ratepayers (RR-EFSB-33);
- Connecticut does require a Noticed Alternative Route, but Rhode Island does not require the presentation of a Noticed Alternative Route.

The Company also observed that although "in most instances the costs and burdens of including a Noticed Alternative Route outweigh the benefits, certain projects could benefit from the inclusion of a Noticed Alternative Route" (RR-EFSB-33). The Company suggested that the inclusion of a Noticed Alternative Route might have benefits, but only for those projects that are located primarily within city streets where route candidates are often in close proximity to each other.

Question for the Board

Should the EFSB continue its practice of requiring both a Primary and a Noticed Alternative Route for transmission projects?

Options for the Board Consideration

1. Continue requiring both a Primary and a Noticed Alternative Route;

2. Leave it to the discretion of the applicant as to whether it presents both a Primary and an Alternative Route or only a Primary Route;

3. Direct future petitioners to seek guidance on the need for a Noticed Alternative Route from Siting Board staff during pre-filing discussions;

4. Defer the consideration of the practice of requiring a Noticed Alternative Route to another proceeding such as a Notice of Inquiry.

VI. ZONING EXEMPTION REQUEST

NEP requested both individual and comprehensive exemptions from the Board from the Millbury, Sutton, Northbridge, Uxbridge and Millville zoning bylaws. NEP's requests range from three to 15 individual zoning exemptions for each municipality. The standard of review for individual zoning exemption requires: (1) a finding that the petitioner qualifies as a public service corporation; (2) that the petitioner requires the exemption; and (3) the present or proposed use of the land or structure is reasonably necessary for the public convenience or welfare.

The Company did not file any petitions for zoning relief with the towns of Millbury, Sutton, Northbridge, Uxbridge and Millville. The towns of Millbury, Sutton,[12] Northbridge, Uxbridge and Millville have all written letters of support for the Board's granting of both individual and comprehensive zoning exemptions. In addition, the Company conducted outreach to the town governments, and none of the communities intervened in the proceeding.

The Company maintains that the zoning relief that would be needed to construct the proposed Project is extensive and complex. NEP states that it is seeking zoning relief in order to allow for the timely, efficient, and consistent construction of the Project. The Company asserts that the need for IRP is immediate in order to maintain reliable transmission service throughout eastern New England. The Company states that it is requesting a comprehensive zoning exemption because

[12] In a December 28, 2011 letter to the Company, Sutton stated it would support such exemptions "provided the Town and its citizens will have an opportunity to comment on the Project at a public hearing in one or more of the Massachusetts towns in which the Project will be located and that the notice of such public hearing will be sent to abutters of the Project, as well as Town officials" (Exh. NEP-2-1, Attachment G). Staff notes that the public comment hearing held in Uxbridge afforded such an opportunity.

there is a continuing risk of the occurrence of an N-1 or N-1-1 contingency until the system is reinforced.

In reviewing requests for comprehensive zoning exemptions under G.L. c. 40A, § 3, both the Department and the Board have stated that such requests are reviewed on a case-by-case basis, and granted only where the applicant demonstrates that issuance of the comprehensive exemption could avoid "substantial public harm" by serving to prevent delay in the construction and operation of the proposed facility. The Department and the Board have cited additional factors as relevant in making such a determination, including whether: (1) the project is needed for reliability; (2) the project is time sensitive; (3) there are multiple municipalities involved that could have conflicting zoning provisions that might hinder the uniform development of a large project spanning these communities; and (4) the communities affected by the project have demonstrated their support for a comprehensive zoning exemption.

Recently, the Board granted requests for a comprehensive zoning exemption in NEP Hampden and Western Massachusetts Electric Company, EFSB 08-2/D.P.U. 08-105/08-106 (September 28, 2010) ("GSRP"). The Board cited the fact that the Hampden and GSRP transmission projects were needed for reliability, and that each affected city and town had expressed its support for the Siting Board's issuance of zoning exemptions.[13] The Board also stated that the exemptions would ensure uniformity in the development of large projects that span multiple municipalities.

By contrast, the Board denied a request for a comprehensive zoning exemption in NSTAR Electric Company, EFSB 10-2/D.P.U.10-131/132 (April 27, 2012) ("Lower SEMA"). The Board found that the need for the project was not so acutely time-sensitive that a comprehensive exemption was needed to prevent substantial harm, nor was the Board satisfied that the municipalities had affirmatively indicated their support for such exemptions (only one of the affected towns in that case expressed support for the Siting Board's issuance of a comprehensive zoning exemption). Further, the Department has denied requests for a comprehensive zoning exemption in the following three cases, New England Power Company, D.P.U. 12-02 (October 9, 2012) ("NEP Westborough"); NSTAR Electric Power Company , D.P.U. 11-80 (July 9, 2012) ("NSTAR Plympton"); and Tennessee Gas Pipeline Company D.P.U. 11-26 (January 6, 2012) ("Tennessee Southwick"). The Department found the projects were not time-sensitive, and were subject to only a single municipality's zoning ordinance, which eliminated the concern about ensuring the uniformity of IRP in multiple jurisdictions.

Questions for the Board

1. Should the Board grant the requested individual zoning exemptions?

2. Should the Board grant the requested comprehensive zoning exemptions?

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[13] In GSRP, all five towns expressed support for both individual and comprehensive zoning exemptions. In NEP Hampden, the Board noted that it was unclear whether the municipal letters of support applied to both individual and comprehensive zoning exemptions.